STATE OF CALIFORNIA – THE RESOURCES AGENCY GRAY DAVIS, ***Governor***

CALIFORNIA ENERGY COMMISSION
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June 1, 2000

Mr. Bruce Kaneshiro
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c/o Public Affairs Management
101 The Embarcadero, Suite 210
San Francisco, CA 94105

Re: California Energy Commission Scoping Comments On CPUC Notice Of Preparation For Environmental Impact Report On PG&E Hydro Valuation & Divestiture (Application No. 99-09-053, State Clearinghouse Number 2000042110)

Dear Mr. Kaneshiro:

On April 27, 2000, the California Public Utilities Commission (CPUC) released a Notice Of Preparation (NOP) of an Environmental Impact Report (EIR) for Pacific Gas and Electric Company's (PG&E's) Hydroelectric Valuation and Divestiture Application (A. 99-09-053), and solicited comments on the NOP by June 1, 2000. The California Energy Commission (Energy Commission) has reviewed the NOP and its staff is pleased to offer the attached comments on the proper scope and content for the EIR in this proceeding.

The Energy Commission looks forward to actively participating in this important CPUC proceeding, and we thank you for considering the comments attached hereto. If you have questions concerning this material, please feel free to contact me personally, or you may contact the individual Energy Commission staff members whose names are listed at the end of these comments.

Sincerely yours,

STEVE LARSON
Executive Director
California Energy Commission

California Energy Commission Scoping Comments On CPUC Notice Of Preparation For Environmental Impact Report On PG&E Hydro Valuation & Divestiture (Application No. 99-09-053)

I. INTRODUCTION

On April 27, 2000, the California Public Utilities Commission (CPUC) released a Notice Of Preparation (NOP) of an Environmental Impact Report (EIR) for Pacific Gas and Electric Company's (PG&E's) Hydroelectric Valuation and Divestiture Application (A. 99-09-053), and solicited comments on the NOP by June 1, 2000. The California Energy Commission (Energy Commission) has reviewed the NOP and is pleased to offer the following comments on the proper scope and content for the EIR in this proceeding.

A. The Energy Commission Has Expertise and Interest In This Matter

For over 25 years, the Energy Commission has been charged by law with exclusive jurisdiction in certifying all thermal power plant sites and related facilities in California with installed capacity of 50 megawatts (MW) or more. The Energy Commission's power plant siting program is fully certified under CEQA by the California Resources Agency.[1] Accordingly, the Energy Commission employs a full-time staff with expertise in a wide range of environmental and energy issues pertaining to large power plants and related facilities throughout the State of California.

In addition, the Energy Commission has numerous responsibilities related to the collection, analysis, and dissemination of detailed information concerning "all forms of energy supply, demand, conservation, public safety, research, and related subjects."[2] In this regard, the Energy Commission employs a full-time staff with expertise in relevant matters such as electricity power supply, demand, price and related issues.

The Energy Commission has both the expertise and the interest in assuring that the EIR in this proceeding is complete and accurate. In this spirit, we offer the following Comments on the NOP.

B. The Energy Commission Supports The Basic Scope Of The NOP

With certain exceptions noted throughout these Comments, the Energy Commission basically supports the NOP's proposed scope for the EIR in this proceeding. We find that the analyses proposed in the NOP are critical for full disclosure and evaluation of the potentially significant environmental impacts associated with PG&E's proposal, and we specifically agree that:

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[1] Public Resources Code (PRC) Section 25500 ***et seq.,*** and Title 14, CCR, Section 15251(k).

[2] PRC Sections 25216.5(d) and 25309.3(c)

- The EIR must "fully disclose all of the potential significant physical and environmental consequences" of the proposal, identify "feasible measures that could be undertaken to avoid or lessen the magnitude of the [adverse] impacts," and "consider the effect of the project on public interest values, including the protection of the environment." (NOP, page 1). The Energy Commission recommends that electric system reliability, power supply adequacy, and the potential for energy market price manipulation be included among the impacts studied.

- The EIR must identify and evaluate PG&E's "operational constraints (i.e., minimum stream flows, and reservoir operation requirements) . . . to determine the flexibility in operations available to new owners of the hydroelectric plants." (NOP, page 2). The Energy Commission recommends that these operational constraints be explicitly examined under a range of possible hydrologic conditions that could occur, given the wide annual variation in hydrology in the historical record.

- The EIR must identify and evaluate how PG&E's "water rights and contractual obligations . . . constrain PG&E's operations" and to what extent the resulting "operational flexibility" might allow "third party purchasers to legally operate [PG&E's] hydroelectric facilities in a manner that could cause significant environmental effects." (NOP, page 3). The EIR should take into account the foreseeable possibility that revenue maximization by new owners in the restructured electricity market could result in significant and different impacts from those experienced under traditional cost-of-service regulation of utility hydro assets.

- The EIR must "evaluate the size and nature of the bundles proposed by [PG&E]." (NOP, page 4). In particular, the EIR should determine whether the proposed bundling of hydro assets could have significant effects on market power in the electricity market or on the efficiency of resource utilization.

- The EIR must "consider whether any expansion, modification or dismantling of facilities would be reasonably foreseeable as a result of a divestiture." (NOP, page 5). If so, the impacts of such activities should be fully explored in the EIR.

- The EIR must "consider a broad range of ownership interests that may affect the operation of and, therefore, the impacts from the proposed transfer of assets." (NOP, page 5). We believe that the NOP is correct in assuming that various purchasing entities may have "interest in consumptive water use, power generation, or dismantling and restoring the site," and the EIR must describe the foreseeable direct and cumulative impacts resulting from such interests.

- The EIR must analyze "both site-specific and cumulative effects." (NOP, page 5). We recommend that this include cumulative impacts which may extend beyond the physical boundaries of the assets proposed for sale by auction.

- The EIR must "contain an analysis of alternatives" and must study "the potential environmental effects of a reasonable range of feasible alternatives." (NOP, page 5).

Elsewhere in these Comments, we describe several alternatives for inclusion in the scope of the EIR, although this list is not meant to preclude other feasible alternatives.

C. Adequate Time Is Needed To Prepare An Adequate EIR

The Energy Commission is concerned that the time allowed for preparation and review of the EIR may not be adequate to fully address the broad range of complex environmental issues associated with the proposed project and feasible alternatives. The Energy Commission notes that its power plant licensing proceedings typically take at least one full year to complete, and the Federal Energy Regulatory Commission's (FERC) hydroelectric generation relicensing proceedings often take five years or more.

The project being considered in this EIR involves numerous power production facilities and land assets with a variety of environmental, energy, economic, and other public-interest values. In many ways, the impacts associated with PG&E's hydropower system are more dynamic, less easily defined, and more ecologically problematic than the impacts associated with a typical fossil power plant.

While the Energy Commission understands that AB 1890 requires a basic asset "valuation" by December 31, 2000, the time currently allocated for environmental review of PG&E's proposed "price-only auction" (an auction which is <u>not</u> required by AB 1890) appears insufficient to fully capture the complexity of issues involved with such an auction. Given this timing concern, we recommend that the CPUC consider establishing an interim "valuation" of PG&E's hydroelectric assets, thus satisfying AB 1890's "valuation" time constraints, and then extend the schedule on PG&E's "auction" proposal, as needed, to ensure that a complete and accurate EIR is prepared and reviewed regarding such an auction.

II. SPECIFIC COMMENTS ON THE SCOPE OF THE EIR

A. Description And Purpose Of The Proposed Project

The NOP describes the project for CEQA purposes as simply "the transfer of ownership, and the possibility that ownership change, and perhaps ownership by multiple entities, would result in changed operation of the Pacific Gas and Electric Company's hydroelectric generation assets, including the lands for sale."[3] The Energy Commission believes that this description does not adequately identify the purpose of the project, which is essential for determining the range of feasible mitigation measures and alternatives to be addressed in the EIR.

[3] Notice of Preparation, Environmental Impact Report for the Proposed Valuation and Divestiture of Hydroelectric Generation and Related Assets by Pacific Gas & Electric Company, Application No. 99-09-053, California Public Utilities Commission, April 27, 2000, p.1.

Specifically, the EIR needs to accurately and fully describe the purpose of the proposal. If, for example, the purpose of the project is to establish the value of PG&E's hydroelectric assets (as required under AB 1890), then there are a range of feasible project alternatives which could meet this purpose, and PG&E's application for market auction and divestiture would be only one method for setting the valuation levels relevant to Competitive Transition Cost (CTC) recovery. In fact, AB 1890 expressly allows other valuation methods including "appraisals" and negotiated "sales."[4] In short, a clear and accurate statement of the purpose of the project must be provided in the EIR, and that purpose must be considered carefully when evaluating the feasibility of mitigation measures and alternatives to PG&E's proposed auction.

B. Baseline Conditions

Under current CEQA guidelines, "baseline" conditions against which the impacts of a proposed project are evaluated are "normally" established as of the date on which the NOP is released.[5] If such a baseline were to be used in this EIR, it would fully describe such things as the physical conditions of the terrestrial and aquatic environment, the hydropower production levels, the energy markets, and the laws, ordinances, regulations, and statutes applicable to each resource area on April 27, 2000.

However, while a "baseline" description could be developed using such a single "snap shot" time frame alone, the Energy Commission believes that the unique and dynamic nature of PG&E's hydroelectric system requires that the EIR contain a reasonable range of scenarios or sensitivities which more accurately reflect the significant annual variations which routinely affect both the environment and the operations of these facilities and other assets. We specifically recommend that such "baseline" scenarios include, but not be limited to, annual and seasonal variations in hydrological conditions (e.g., dry, normal and wet years) and annual and seasonal temperature-dependent changes in electricity demand.

In developing the appropriate baseline conditions for this project, the EIR should also clearly describe PG&E's traditional environmental-stewardship policies, programs, and achievements, which have been recognized by major governmental organizations, non-governmental organizations (NGOs), environmental groups, and the media. PG&E's traditional resource management policies tend to reflect a "superior environmental stewardship" baseline, rather than a "minimum legal compliance" baseline, and this should be reflected in the "baseline" conditions which are adopted for the purposes of this project. These traditional resource management policies, programs, and achievements are a matter of public record. For example, PG&E's Annual Corporate Environmental Quality Reports are a rich compendium of these policies, programs and

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[4] Public Utilities Code Section 367(b) states that "value shall be determined not later than December 31, 2001, and shall be based on ***appraisal, sale, <u>or</u> other divestiture.***" Clearly, a price-only auction is not the only means by which this provision of AB 1890 can be satisfied.

[5] ***See*** Title 14, CCR, Section 15125(a).

achievements. We recommend that such policies, programs, and achievements be incorporated into the baseline description.[6]

Finally, we note that the EIR in this proceeding will also be relevant to and will inform the CPUC's decision-making process in determining the "public interest" under Public Utilities Code Section 851. As the Assigned Commissioner and the ALJ in this proceeding have indicated, this public interest determination must take into account the existing environmental impacts of the hydropower system, the potential environmental effects of the proposed project evaluated in the EIR, and the power production, water, and recreation opportunities and benefits associated with the assets.[7] However, we think it is important to note that while CEQA is a powerful analytic tool, its legal bounds may preclude using the EIR, itself, to examine all relevant public-interest issues which must be assessed in the final "public Interest" determination. If the CEQA review process alone does not provide sufficient information in these areas, we recommend that the CPUC consider undertaking parallel studies to meet all of its public-interest determination needs.

C. Project Impacts And Mitigation

In analyzing project impacts, the Energy Commission makes the following suggestions on issues that should be adequately assessed.

1. "Worst Case" Impacts

PG&E's proposed price-only auction for its hydroelectric facilities and associated lands cannot determine the primary motives, interests, and financial capabilities of the bidders. Therefore, the Energy Commission recommends that the EIR assume a reasonable "worst-case" scenario, consistent with CEQA guidelines, when making assumptions about the future owners and operations of these assets. This scenario should be bounded by license and contractual constraints, including constraints imposed by Reliability Must Run (RMR) contracts between the generator and the California Independent System Operator (Cal ISO).[8] At a minimum, this "worst-case scenario" should include the following assumptions:

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[6] We also note that Energy Commission staff has been active since 1996 in the Utility Lands Working Group, an interagency task force that worked cooperatively with PG&E up through 1999 to identify PG&E lands with natural-resource features and values important enough to merit potential government acquisition. We recommend that the work of this group be used to help establish the baseline conditions.

[7] ***See*** Ruling of Assigned Commission and the Administrative Law Judge Regarding Motion for Clarification and Amendment of the Procedural Schedule, February 28, 2000.

[8] RMR contracts are one mechanism the Cal ISO uses to mitigate local market power or local reliability problems. The physical location of a power plant within the interconnected system can bestow on it the ability to exercise market power by virtue of the necessity that it be running to maintain local system reliability or the fact that there is an insufficiency of competing suppliers of energy or ancillary services so as to avoid price manipulation. If the plant is necessary for reliability purposes, the RMR contract establishes terms and conditions by which those services are provided and compensated, including a prohibition that the plant not be decommissioned until a substitute can be provided to maintain local system reliability.

- Firms operating in a market environment, where costs are not ratebased as they were under monopoly regulation, will have different financial motivations in making resource-allocation decisions.

- Debt assumed to finance hydro-system elements will motivate new owners to maximize revenues from newly acquired power, land, and water assets, potentially at the expense of environmental quality where costs are not internalized.

- New owners will be reluctant to voluntarily allocate more than the minimal expenditure necessary for environmental compliance (in contrast to utility behavior in a regulatory setting).

- Environmental compliance in a revenue-maximizing environment will meet only minimum legal standards.

Although the outcomes and environmental consequences of these "worst case" assumptions may be difficult to measure, the resulting direct, indirect, or cumulative environmental impacts from such a scenario must be fully assessed under CEQA.

2. Cumulative Impacts

The EIR must identify and analyze the full range of environmental impacts described in the CEQA Guidelines (e.g., Appendix G). This would include, but is not limited to, identifying and quantifying potential impacts to: land and water-based recreation, open space, water quality and supply, forest preserve, carbon sequestration, wetlands, riparian zones, terrestrial habitats, aquatic habitat for anadromous and non-migratory species, endangered species habitat, and amenity values for rural quality of life including scenic open space.

However, it is essential to recognize that environmental impacts may well occur beyond the physical boundaries of the specifically defined project, particularly since this is a complex project involving a large, wide-spread hydro system and related lands and other assets. Therefore, the Energy Commission recommends that, in analyzing cumulative impacts, the EIR examine cumulative impacts by bundles of facilities, by entire affected watersheds, and by all reasonable combinations of facilities or river systems. This cumulative impact analysis must fully describe any "spillover" impacts to resources and locations beyond the boundaries of the specific assets proposed for auction.

3. Impacts From Possible Decommissioning Of Facilities

As mentioned in the NOP, the EIR should describe and analyze how the decommissioning of certain project facilities will be handled under the proposed project and possible project alternatives. At a minimum, the EIR should identify which, if any, project facilities are reasonably likely to be decommissioned for economic or environmental reasons, and how such foreseeable decommissionings would be affected by the proposed project or project alternatives. We also note that such decommissionings could be an element in various project mitigation packages.

In considering the scope of the decommissioning impacts analysis, the EIR should recognize that societal values and energy-generation technologies are evolving over time, and decommissioning of hydroelectric energy facilities may become increasingly "feasible" as society seeks to protect or restore other natural resources and societal values for present and future generations. Recent examples of this evolution include the removal of some PG&E facilities on Battle Creek, and current studies on possible removal of Englebright Dam and related PG&E facilities on the Yuba River. Both decommissioning projects have found it feasible to forego certain energy and economic benefits from existing facilities in order to restore salmon and steelhead trout habitat.

In deciding which facilities to consider for decommissioning, we recommend that the EIR evaluate low-power output, environmentally inefficient facilities using a well-defined set of environmental and economic criteria. "Environmentally inefficient" is intended to denote facilities that produce disproportionate levels of environmental impact per unit of energy produced. Tools and criteria needed to assess the environmental efficiency of hydro plants could be drawn from the following green energy labeling systems:

- Life Cycle Impact Assessment – ISO 14020 Standards
- Green Hydro Assessment Systems (American Rivers, Green-e, Northwest, etc.)

4. Impacts On Stranded Public Benefits

PG&E's proposed price-only auction frames asset valuation strictly in terms of privately financed and managed assets. The "value" of the hydro-related lands and waters are nearly always expressed in terms of the book value, capitalized improvement, stranded assets, market power, or energy prices. Proceeds are portrayed in terms of shareholder return, CTC pay-down or rate reductions. Public-trust resources and other potentially "stranded public benefits" are generally lost in such portrayals.

The discrepancy between non-monetized public trust benefits and market-auction values may be substantial, and may form the basis for subsequent "feasible" mitigation. Therefore, we believe that the EIR must thoroughly examine the natural resource values of the assets affected by the PG&E proposal as well. Resource-economics studies (e.g., natural resource damage assessment or contingent valuation) can identify and quantify the public-good or public-trust values associated with these assets, and will help to ensure that ratepayers and the general public receive a full accounting of such non-monetized assets.

5. Energy Impacts

(a) Energy System Context

The impacts of the project and alternatives on California's energy system need to be clearly delineated. However, the hydroelectric system is only one of a number of generation options that is available to the State to meet future demand. The restructured electricity market is a dynamic and evolving market. Some parties in discussions about the future disposition of hydroelectric assets may be under the impression that decommissioning of particular hydro facilities or bundles of facilities will result in electricity shortages in the State. This may not be the case, and the EIR certainly needs to fully and accurately address this issue.

For example, the NOP describes the PG&E hydro system as providing 3,896 MW of peak capacity, and about 5 percent of the State's annual average electric energy (GWh) supply. However, the EIR needs to make clear that the actual capacity output and amount of energy these facilities provide varies significantly from year-to-year, depending on seasonal precipitation. The total PG&E hydro generation has ranged from a low of 10 billion kWh in the drought year of 1977 to a high of 40 billion kWh in the very wet year of 1983.

In addition, the EIR should note that after the passage of AB 1890, a number of proposed multi-billion dollar investments in new, natural gas-fired, combined cycle energy systems are likely to result in large MW capacity additions of thermally efficient energy sources within California. As summarized in the table below, just since the passage of AB 1890 the Energy Commission has received or is currently expecting to receive permit applications for 46 large power plants with an installed capacity of over 26,000 MWs.[9]

Siting Status	No. of Cases	Total MW	Capital Investment ($ billion)
Approved	5	3,648	2.08
Current	12	7,306	4.0
Future (Confirmed)	29	15,422	8.88
Totals	46	26,379	14.96

In addition to the large new natural gas-fired capacity listed above, increased investments are also occurring in sub-50 MW natural gas-fired plants and renewable resources such as wind and solar. New technologies such as distributed generation and fuel cells are also becoming viable.

In short, the EIR needs to make clear that the energy-supply situation is dynamic and will be different in five, ten and twenty years. Decisions made in the 2000-2002 time

[9] It is the Energy Commission Staff's objective that new fossil-fueled power plants contribute to no net increase in air emissions in criteria pollutants in air basins that are not in attainment of air quality standards.

frame about the value and role of hydropower in the State's electricity supply mix should consider anticipated future supply scenarios over time.[10]

(b) Potential Energy System Effects

Potential changes in the ownership or operations of PG&E's hydroelectric assets might negatively affect the efficiency of pricing energy services, the ability of market regulators to detect and police attempts to manipulate market prices, and the ability of control-area operators to meet reliability requirements. The EIR should analyze the proposed project and alternatives to assess the extent that ownership or operations changes might:

- Reduce the economic efficiency of energy pricing by allowing capacity-withholding behavior or limiting the ability of the California Power Exchange (Cal PX) Market Monitoring Committee or the Cal ISO Department of Market Analysis to remedy such behavior.

- Reduce the economic efficiency of ancillary-services pricing by allowing capacity-withholding behavior that leads to bid insufficiency and thin markets or limiting the ability of the Cal PX Market Monitoring Committee or the ISO-Department of Market Analysis to remedy such behavior.

- Encourage behavior that creates artificial congestion or otherwise reduces the efficiency of congestion prices to serve as signals for the location of new generation or transmission upgrades.

- Negatively affect the ability of the Cal ISO to meet Western States Coordinating Council (WSCC) reliability requirements, i.e., to maintain adequate spinning reserves, non-spinning reserves, replacement reserves, frequency regulation, voltage support, black-start capability.

- Negatively affect the ability of the Cal ISO to mitigate locational market power or mitigate local-area reliability problems at reasonable cost.

- Constrain the ability of the Cal ISO Department of Market Analysis or the Cal PX Market Monitoring Committee to prevent or remedy significant abuses of market power using their established methods of monitoring.

The contractor should also separately assess how the effects identified in the above analysis might change, assuming the following mitigation measures had been imposed as environmental mitigation:

[10] The PUC staff and its contractor team are welcome to examine the environmental data contained in the record of any of the Energy Commission's siting cases completed or underway. The most relevant case may be the Three Mountain Power project, located in Burney, Shasta County. Burney is proximate to Lake Britton and the Pit River hydropower system. The PUC staff and its contractor team are welcome to consult with CEC Staff on any energy-related issues of interest.

- Changes in flow regime and scheduling to enhance fisheries, water quality, or recreation benefits.

- Capital improvements for fish passage.

- Decommissioning.

D. Project Alternatives

The Energy Commission recommends that the EIR assess a reasonable range of feasible alternatives. In **Appendix A to these Comments**, the Energy Commission has provided its characterization of the project, itself, and two other feasible alternatives including:

- Proposed Project: CPUC-approved Auction

- No-Project Alternative: Retention by PG&E Under Current CPUC Regulation

- PBR Alternative: Retention by PG&E Under New PBR Regulation by the CPUC

However, the Energy Commission recognizes that there are likely to be other feasible alternatives as well, and we in no way intend these Comments to foreclose the EIR from analyzing other feasible alternatives as well.

III. CONCLUSION AND CONTACTS

The Energy Commission appreciates this opportunity to respond to the NOP and provide input on the scope of the EIR in this important CPUC proceeding. Our staff contacts for additional information on this matter are Jim McKinney (Siting Division), Ross Miller (Energy Assessments Division) and Monica Schwebs (Chief Counsel's Office).

Appendix A

Electricity System Description Of Project And Alternatives

1. Proposed Project: CPUC-Approved Auction

The CPUC approves an auction process. The auction is conducted according to the approved process. The hydroelectric assets are auctioned off in bundles to the highest qualified bidders. The CPUC approves and, perhaps, conditions the resulting ownership transfers to new owners, making the necessary findings that the auction process had been adhered to and that the transfer is in the public interest. Asset revenues, less capital gains taxes, are credited to the transition cost balancing account to offset customer obligations to uneconomic generation and other transition costs (in lieu of the future annual revenues from the sale of hydroelectric power).

Bidders may include, but are not necessarily limited to, private unregulated energy generation companies (including the PG&E unregulated subsidiary), publicly-owned electric or water industry entities (municipals, irrigation districts, federal power operators or marketers), privately-owned electric or water industry entities (including out-of-state electric utilities), recreational interests, or environmental interests, or any combination of these acting as joint bidders. PG&E employees continue to operate the facilities for two years from the time of divestiture if the new owner planned to continue generating power. After that two-year period, other employees could operate the facilities.

The new owner may bid power from the assets into qualified energy and ancillary market exchanges, sell it under bilateral contracts to any electricity retailer or wholesale customer, retain the power for its own use or retail sale, or otherwise utilize the asset for its own purposes. The power accepted through exchange bidding receives a price in accordance with the pricing scheme established by that qualified exchange. New owners could operate to maximize electricity energy or ancillary services market revenues, RMR or bilateral contract revenues, revenues from using facility resources for purposes other than generation of electric energy or for any other purpose that does not violate applicable laws or regulations. New owners expect revenues from the asset to be sufficient to recover expenses, repay debt and provide a return to investors commensurate with risk.

The CPUC may condition the sale of the asset, if necessary, to protect the public interest, including a CPUC finding that no over-concentration of market power would be created by the divestiture, but would exercise no regulatory control over plant operations or disposition after divestiture. After the divestiture, potential anti-competitive behavior or exercise of local or general market power is subject to:

- terms and conditions of RMR contracts if the ISO determined such contracts are necessary;
- a FERC finding of absence of market power potential before it approved the new owner's application to sell at market based rates;
- any ongoing hourly market power surveillance regulation by applicable qualified energy exchanges and the ISO Department of Market Analysis;

- periodic and ad hoc FERC review of market behavior.

The operations of the hydroelectric asset are subject to FERC license and other contractual constraints. Operations are also subject to control area interconnection and reliability criteria. The plant could not be decommissioned until and unless the control area operator (e.g., the ISO) determines the plant is not necessary for electrical system reliability. If necessary for reliability and or market power purposes, control area operator practices and possibly RMR contract terms further constrain operations and disposition of the plant.

2. No Project Alternative: Retention By PG&E Under Traditional CPUC Regulation

PG&E retains the hydroelectric generation assets within its regulated corporate entity. The CPUC oversees PG&E's use of the assets under a traditional cost of service regulatory scheme.

Until the end of the transition period (assume March 31, 2002), PG&E receives existing ratemaking treatment for hydro facilities, as detailed in D.97-12-096. All hydro output is bid into the PX energy market (or other qualified exchange pending CPUC resolution of this issue in A.99-01-016 ***et al***) and the ISO ancillary services markets. The power bid into markets receives the hourly market-clearing price or could set that price if its bid was the last bid accepted. The difference of electricity revenues less O&M costs, if positive, is credited to the transition cost balancing account to offset uneconomic generation and other transition costs.

After the transition period, PG&E shareholders continue to own and operate (with PG&E employees) the hydro facilities indefinitely. The CPUC institutes a cost of service ratemaking mechanism in which PG&E recovers reasonable costs dollar for dollar and shareholders earn an authorized rate of return on undepreciated investment in the hydro facilities. PG&E sells hydro output into the PX or other energy and ancillary market exchanges, or sells it under bilateral contracts with electricity retailers or wholesale customers. The power bid into exchanges would receive the hourly market-clearing price or could set that price if its bid was the last bid accepted.

All revenues less reasonable costs are credited to the Transition Cost Balancing Account (TCBA). If the allocated revenues exceed ongoing Competitive Transition Cost (CTC) amounts, the excess revenues are returned to all customers either through a CTC credit on customer bills or a revenue-level credit against regulated distribution or transmission costs. (They would not be credited against energy purchase costs, which would be an unfair competitive advantage relative to other competing energy and ancillary service suppliers).

All utility expenses and utility electricity sales performance are subject to reasonableness review. Furthermore, the CPUC conducts periodic reviews to evaluate the conditions under which PG&E operates the facilities. Among other things, these reviews will examine expenses ratios such as administrative and general (A&G) and operations and maintenance (O&M) adders, costs associated with compliance with FERC licensing criteria, etc. Allocation of costs and revenues among customers is reviewed in the periodic general rate cases evaluating overall utility operations.

Potential anti-competitive behavior or exercise of local or general market power is subject to:

- evaluation in CPUC reasonableness reviews or general rate cases;
- terms and conditions of RMR contracts if the ISO determined such contracts are necessary;
- any ongoing hourly market power surveillance regulation by applicable qualified energy exchanges and the ISO Department of Market Analysis;
- periodic and ad hoc FERC review of market behavior.

The operations of the hydroelectric asset are subject to FERC license and other contractual constraints. Informal operation agreements with parties are subject to the CPUC's review of reasonableness of those self-imposed constraints in the current and future energy market environment. Operations are also subject to control area interconnection and reliability criteria. The plant could not be decommissioned until and unless the control area operator (e.g., the ISO) determined the plant was not necessary for electrical system reliability. If necessary for reliability purposes, control area operator practices and possibly RMR contract terms will further constrain operations and disposition of the plant. As it currently does, PG&E will have to apply for CPUC review and approval for significant changes, including future spin off or other divestiture requests.

3. PBR Alternative: Retention By PG&E Under New PBR Regulation By CPUC

PG&E retains the hydroelectric generation assets within its regulated corporate entity. The CPUC continues to regulate PG&E's use of the assets according to principles similar to those proposed for Edison's retention of its hydroelectric assets.

PG&E employees continue to operate the facilities indefinitely. An above-book but below-market value for the hydro assets is negotiated to create a regulatory asset that is depreciated over 40 years. The above-book amount is credited to Utility Distribution Company (UDC) ratepayers to offset uneconomic generation and other transition costs. The CPUC raises the authorized rate of return on investment, and shareholders also receive a small share of net profits from electricity sales revenues (not large enough to motivate operation changes to manipulate market price but large enough to encourage efficiency improvements).

Until the end of the transition period (assume March 31, 2002), PG&E continues to bid all of the power from the assets into the PX energy market, other authorized exchange and the ISO ancillary services markets. The power bid into markets receives the hourly market-clearing price or sets that price if its bid was the last bid accepted. Most of the electricity revenues, less O&M costs, are credited back to PG&E UDC ratepayers to offset uneconomic generation and other transition costs. A small fraction of net revenues is credited to shareholders as an incentive for efficient operations, but not so large as to motivate behavior to manipulate the market prices.

After the end of the transition period, PG&E can bid any or all of the power from the assets into the PX or other energy and ancillary market exchanges, or sell it under bilateral contracts to any electricity retailer or wholesale customer. The power bid into exchanges would receive the hourly market-clearing price or could set that price if its bid was the last bid accepted. A small fraction of net revenues is credited to shareholders as an incentive for efficient operations, but not so large as to motivate behavior to manipulate the market prices. But most revenues from all electricity sales are credited to the TCBA. If the allocated revenues exceed ongoing CTC amounts, the excess revenues are returned to all customers either through a CTC credit on customer bills or a revenue-level credit against regulated distribution or transmission costs. (They would not be credited against energy purchase costs, which would be an unfair competitive advantage relative to other competing energy and ancillary service suppliers).

The CPUC revisits the PBR mechanism only every eight years. Potential anti-competitive behavior or exercise of local or general market power would be subject to:

- evaluation in CPUC review every eight years;
- terms and conditions of RMR contracts if the ISO determined such contracts are necessary;
- ongoing hourly market power surveillance regulation by PX Market Monitoring Committee, and the ISO Department of Market Analysis;
- periodic and ad hoc FERC review of market behavior.

The operations of the hydroelectric asset are subject to FERC license and other contractual constraints. Informal operation agreements with parties will be subject to the CPUC's eight-year review of the reasonableness of those self-imposed constraints in the current and future energy market environment. Operations are also subject to control area interconnection and reliability criteria. The plant could not be decommissioned until and unless the control area operator (e.g., the ISO) determined the plant was not necessary for electrical system reliability. If necessary for reliability purposes, control area operator practices and possibly RMR contract terms would further constrain operations and disposition of the plant. As it currently does, PG&E would have to apply for CPUC review and approval for significant changes, including future requests spin off or other divestiture.

The CPUC can require PG&E to perform environmental remediation studies if the benefits of doing that are demonstrated. The CPUC can require an electricity bill line item that allows ratepayers to volunteer an extra amount of payment for environmental remediation. Decommissioning accounts are pre-funded to help remove objections to initiating decommissioning proceedings for unused or otherwise uneconomic facilities that continue to have an environmental effect.